DOWNHOLE FLOW CONTROL APPARATUS, SUPER-INSULATED TUBULARS AND SURFACE TOOLS FOR PRODUCING HEAVY OIL BY STEAM INJECTION METHODS FROM MULTI-LATERAL WELLS LOCATED IN COLD ENVIRONMENTS

FIELD OF THE INVENTION

Very large volumes of Heavy Oil (API gravity =< 19 Degrees) have been discovered in the Alaskan Arctic, Onshore, below a 1,800 ft-thick Permafrost zone, which are in reservoir rocks at un-usually low temperature, because of their proximity to the overlaying Permafrost.

The viscosity of the Heavy Oil in those reservoirs is known to be, correspondingly, very high, which, by consequence, restricts its natural in-flow rate into conventional production wells to mostly un-economic values. This explains that only a very small portion (5 to 10 %) of those huge Domestic oil resources (up to 40 Billion Barrels estimated Original Oil In Place) has been developed, more than 25 years after their discovery.

More recently, other very large Heavy Oil resources were found, Offshore, in deep water, off the coasts of Trinidad, Brasil and West Africa, in equally cold reservoir rocks. These world-wide oil resources are still un-developed, for the same reason as those in the Arctic: an excessive viscosity of the Heavy Oil, limiting the rate of production.

Large volumes of Heavy Oil from warmer reservoir rocks, however, are being economically produced, Onshore, by means of Steam Injection, in California, in Indonesia, in Canada, etc...

The present Invention improves upon US Patent 5,085,275, Ref.(1), by the same Inventor, which teaches a Process in which: "the degradation of Steam quality, due to heat losses prior to its injection into a Heavy Oil reservoir, is reduced by utilizing the heat contained in a stream of reservoir fluids, produced from the same reservoir, following a cycle of steam injection".

FIG.5 and FIG.6, from Ref.(1) and re-named here as FIG. A and B, specifically, address the case of Arctic multi-lateral wells.

In this case, it is essential to prevent any significant heat loss, through the wall of the vertical casing, to the surrounding Permafrost, so as to avoid melting the Permafrost. Such melting would, ultimately, cause the casing to drop down, shearing-off the connecting tubulars to the well head, destroying the well, causing an oil spill and a potential well fire, especially difficult to control in an Arctic climate.

The validity of the Inventor's 1990 prediction of such a potential catastrophic hazard is confirmed by FIG C, taken from Ref. (5), published in 1991, by a group of Engineers from the Oil Operating Companies (ARCO and BP) in the Alaskan Arctic.

FIG C is the result of a numerical simulation of the heat loss and Permafrost melting radius around a cased well containing a single coaxial Steam tubing, either bare or Insulated, based upon the known characteristics of commercially-available, vacuum-insulated, tubings. It shows that, even with such Steam tubing insulation, and a gas-filled casing-tubing annular space, the Permafrost at 1700 ft is melted inside a circle of 6 ft radius at the end of First cycle of Steam Injection. That radius increases to 8.5 ft in cycle 2 and reaches 10.5 ft after cycle 6. Without any insulation, the melting

radius is 20 ft after the First cycle. This illustrates the advantage of using higher-performance,"Super-insulation", materials.

The main objective of the present Invention is to combine the use of "Super-insulated" tubulars with a Downhole Flow Control Apparatus and with Surface Tools to, safely and economically, implement Ref.(1) Process. This Process is based upon the simple idea of reducing Total Steam heat losses by placing an additional "free" heat source around the Steam tubulars, thereby lowering the temperature gradient across the insulation layer. Such an approach was numerically analyzed in Ref. (6) and verified in 1989 by a field test, made by Texaco, in a Kern County, CA, Heavy Oil well, under Dual Steam and hot water injection, in two Oil zones.

The application of this Downhole Apparatus and of the required Surface tools to the known Heavy Oil reservoirs in the Alaskan Arctic will significantly increase Domestic Oil reserves from Onshore fields, without any impact to the environment, over the next 30 years.

The same technology, applied Offshore to Heavy Oil in deep water, will also make it possible to drastically reduce heat losses from the Steam injection tubulars, to the surrounding cold Ocean, thereby reducing Steam consumption, an important cost factor in any Thermal Oil recovery project, in a cold environment.

MULTI-LATERAL WELL CASING-LINER COMPLETION BY PRIOR ART

In an Onshore cold environment, a large-diameter well Casing pipe, or, in deep cold water Offshore, a large Conductor pipe is installed through the total thickness of said cold environment, in a borehole above a targeted Heavy Oil reservoir. The well Casing or the Conductor pipe presents a plurality of windows, precisely cut-out at various depth intervals and oriented in selected directions, below the thick Permafrost zone when in an Onshore Arctic well, or below the Ocean bottom, when in a deep sea Offshore well.

This type of liner to casing connection, taught in Ref. (4), is preferred to those through the casing shoe, as in FIG.B and FIG.C, when a relatively large number (4 to 8) of lateral wells have to be connected to the same casing. This is an important requirement for lateral wells operated under "Sequential Cyclic Steam Injection", in a cold environment. In that most efficient Mode of Operation, one of the wells is under Steam injection, while most of the others are in the Production mode. The optimum Injection cycle duration, however, is much shorter than that of the Production cycle, by a factor of 1/3 to 1/7 in most reservoirs. This difference might result in excessive down-time of boilers. In warm environments, Onshore, this difficulty is very easily overcome by the use of Mobile Steam Generators, which are quickly moved from well site to well site, with little down-time, or by using an Insulated Steam Distribution pipes network, connected to a distant Co-generation Plant.

Such approaches, however, are not cost-effective in the Arctic, nor Offshore, because of excessive heat losses in the distribution pipes or because of excessive cost of frequently moving boilers at sea, from one platform to another.

In FIG.1, the side-way connection of a lateral well to a vertical well casing allows to stack-up a much greater number of multi-lateral wells to the same casing than the schematic connections, through the

casing shoe, shown on FIG. B and C.

A pre-cut short pipe, called a Liner Stub, equipped at its upper end with a sealing collar and closed at its lower end, is inserted, through the matching Casing Window, guided and extended-out, into a pre-drilled side-pocket hole, at a pre-determined orientation and at a small angle from the substantially vertical axis of the Casing or Conductor pipe, as taught in Ref. (4).

A method of fabrication, from blank pipe elements, of the Casing Window and of both ends of the matching Liner Stub is taught in Ref.(3).

Each fully-extended Liner Stub is cemented in its respective side pocket, and cleaned-out of excess cement and of any drillable debris.

It is through each cemented Liner Stub, starting from the lowermost, that a medium to short radius lateral hole is then drilled, following a pre-selected, curved trajectory, reaching the lower part of the Heavy Oil zone. The hole diameter in this curved trajectory is close to the inside diameter of the Liner Stub.

Due to relatively shallow burial depths of Heavy Oil reservoirs, the curved hole stability may be limited, requiring that a Liner be run-in, installed and cemented into the curved hole, as quickly as possible. The Curved Liner's upper end is equipped with a conventional hanger/packer, set within the cemented liner stub. Each lateral hole is then continued by a small-diameter hole, quasi-horizontal, but with a slightly upward slope, which traverses most of the Heavy Oil zone thickness, as determined by known logging tools and directional surveying tools, preferably used in open hole.

A small-diameter Liner pipe string, inserted in each lateral hole, at the end of a work string, is sealed or coupled to the lower end of the larger cemented Curved Liner, forming a Tapered Liner String.

It comprises, from the distant end of the lateral well:
- a perforated small-diameter Liner string, equipped with sand screens and centralizers, or gravel-packed, in the hole's quasi-horizontal portion, within the reservoir,
- a retrievable plug nipple, to be used for isolating the Curved Liner from the quasi-horizontal Liner and an expansion joint; they are located at the proximate end of the small-diameter Liner string, near the lower end of the cemented Curved Liner's shoe, and just below its junction with the larger-diameter cemented Curved Liner string,

The composition of the small-diameter Liner string depends upon the reservoir rock characteristics and heterogeneity. It may include:
- "notched" perforations in the event of future hydro or acid fracs,
- retrievable plug mandrels, for eventual future treatment or gravel-packing of segments of the lateral well,
- sand screens or pre-packed sand filters of various kinds,
- "blank" pipe segments equipped with cement diverter valves, to allow the future cementation of portions of the Liner string, to reduce water production, etc...

In situations where the formations separating the cold environment from the Heavy Oil zone are un-fractured and fully consolidated, the lateral hole drilling and its completion with a Tapered Liner string may, of course, proceed without interruption, so that the cementation of the Curved Liner and its connection to the Liner Stub may then take place at the very end of the completion operations, rather than earlier. In such a case, the coupled Tapered Liner String also presents a cement diverter valve at the base of the Curved Liner, used

for its cementation.
Most elements of such a Multi-lateral Well are "Non-retrievable", nearly all of them being cemented in place, or, permanently affixed to to other cemented elements.

SUMMARY OF THE INVENTION

The present Invention deals with the addition of "Retrievable" Multi-tubular Downhole Apparatus, to be installed within the Casing and Liners (cemented or not) of the above described Multi-lateral Well, so as to produce Heated Heavy Oil, at high rate, from said Multi-Lateral Well, when operated under the "Cyclic Steam Injection and Production Mode", by the Process taught in Ref.1 (US Patent 5,085,275).

The present Apparatus includes, for each lateral well:
A) A DOWNHOLE FLOW-CONTROL APPARATUS, and,
shared between all lateral wells:
B) TWO COAXIAL "SUPER-INSULATED" TUBING STRINGS,
C) SURFACE TOOLS FOR COUPLING "SUPER-INSULATED"JOINTS.

FLOW CONTROL APPARATUS

The Flow-Control Apparatus of each lateral well, which is part of the present Invention, is made-up of three parts, corresponding respectively to items 19, 18, and 17, used in relevant parts of the Process of Ref.(1):

Part 1), a pre-fabricated Dual Tubing Assembly:
It is located in the Curved Liner string of the selected Lateral well. It is terminated at its lower end by a sealing stinger pipe, inserted into the Polished Bore Receptacle (PBR), coupled to the proximate end of the lateral well's Production tubing, hung in the proximate part of the quasi-horizontal liner. Said Assembly is terminated, at its upper end by two similar PBR's, hung in part 2 of the Flow Control Apparatus; It also includes:
a) a cup-packer, used as back-flow preventer,
b) a H or Y connector at the base of said Dual tubings,
c) two modified gas-lift mandrels and their respective retrievable gas-lift valves and, or, check valves,
d) a thermal expansion joint, at the upper end of said curved Production tubing, to offset the differential thermal expansion within said Dual tubings Assembly;

Part 2), is a Modular tubulars and Connectors Section.
It is located in a section of the annular space between the vertical Casing and the coaxial Production Collector tubing, which includes the Liner Stub space of the selected Lateral well. Said section contains a plurality of vertical tubings, all connected to Part 1), by means of sealing stingers at Part 2)'s lower end, and to Part 3) by PBR's at Part 2)'s upper end. It is closed at its lower end by either the Casing shoe or by the multi-tubular Packer associated with the top part of the previously-installed Lateral well. It comprises:
a) a substantially vertical tubular extension of the curved Lift-gas tubing of Part 1), located in a different radial plane than that of a vertical tubular extension of the curved Production tubing. The Lift-gas tubular extension is terminated at its upper end by the slanted branch of an inverted Y connector and at its lower end by a

sealing stinger inserted in the matching PBR at the top end of Part 1). The Lift-gas tubular extension also presents at least two branch flow connectors, within said section of the Casing annular space.

b) a vertical tubular extension of the curved Production tubing, terminated at its upper end by PBR, located above a multi-tubings packer, dedicated to the specific Lateral well, and, at its lower end by a sealing stinger matching the PBR of the curved Production tubing in Part 1). The Production tubular extension also presents at least three branch flow connectors, within said section of the Casing annular space.

Part 3), is a Modular flow control system, using various plugs or valves of various types, controlled from the surface, or automatically actuated by variations of pressure or of fluids density, within the various tubulars in said section of the Casing annular space, and linking, or closing, the respective branch flow connectors of Part 2) with:

- the casing annular space,
- the coaxial Production Collector pipe,
- the central Insulated Steam tubing,
- the Production tubing extension,
- the Lift-gas extension tubular.

The use of plugs, valves, branch flow connectors and tubulars depends upon the three sequential modes of operation of the Lateral well, namely: Steam injection, Steam soak and Oil Production by Gas-lift or Steam-lift processes.

An example of the specific use of each plug, each valve, each branch flow connector and each tubular or annular space will be disclosed in detail by FIG.3 and by Table 1.

It will be apparent to those skilled in the Art that wireline retrievable plugs and valves may be used for the same purposes and that there are many shapes of manifolds or branch flow connectors, which may be used, interchangeably, at different costs, safety factors, reliability or ease of operation and maintenance. To the extent that it is possible to adapt "off the shelf" equipment and devices described in Prior Art, for similar purposes, the Invention extends beyond the specific combination, presented as an example, on FIG.3 and Table 1, below, to all other configurations and devices capable of achieving the same purposes, by similar means, under various well conditions of temperature, pressure, corrosion risks, sand production, etc...

Parts 2 and 3 of the Flow Control Apparatus may be assembled together, run-in and installed as a single Module.

The same system of stacked Downhole Flow Control Apparatus is also applicable to Lateral wells connected through the shoe of a vertical Casing, as in FIG.A or FIG.B, when the Multi-lateral Well has fewer than four Lateral wells. In such a configuration, said shoe presents two or three large traversing holes, substantially vertical, serving the same functions as the same number of side-way Liner Stubs, at a somewhat lower cost.

In very thick Heavy Oil zones, separated by a sufficiently-thick

overburden layer, from the Cold environment, it is also possible to combine two or three Lateral wells, connected through the Casing shoe, and associated with two or three of said stacked Apparatus, with eight Lateral wells, connected to the Casing via Side-way Liner Stubs, similarly associated with a stack of eight said Apparatus. This results in a total of ten to eleven Lateral wells, connected to the same Multi-lateral Well. Each of said Lateral wells is, at any time, independently operable, either in Steam Injection or in Oil Production, or subject to logging, or cleaning operations using conventional tools.

It is also possible to connect a pair of quasi-horizontal Lateral wells with an inverted Y connector to a single cemented curved liner, and to operate both wells in the pair in the same mode of Sequential Cyclic Injection and Oil Production. This approach inceases the drainage area of the Multi-lateral well, while sharing the cost of all the Downhole elements of the present invention, thereby reducing the per-Barrel of Oil, Capital and Operating costs.

"SUPER-INSULATED" TUBULARS

The other parts of the present Invention, required for the implementation of Ref.(1) in Cold environments, are two co-axial strings of "Super-insulated" tubulars, to be handled and assembled on conventional Drilling or Service rigs, from pre-fabricated and factory-tested tubular joints. Each inner string consists of a sealed, dual-wall, coaxial tubular joints, in which the annular space between the two walls is factory-filled with a "Super-insulating" Material, the pore-space of which is gas-filled and kept at a pressure not exceeding that of the atmosphere, within a sealed metal enclosure.

The inner string is then inserted into a conventional protective, pressure-resistant, outer tubular string, also air-filled at atmospheric pressure, to complete the "Super-insulated" Tubular Assembly, dedicated to the conveyance of either Steam or of Hot produced fluid streams.

The inner wall of the inner string is also pressure-resistant, but its outer wall, enclosing the "Super-insulating" Material, and placed within the air-filled enclosing outer string, is made of a thin-gauge metal presenting a higher thermal expansion coefficient than that of steel, such as Zinc and its alloys, so as to minimize the differential expansion between the hot enclosing outer string and the hotter inner string.

Because the thin outer wall is exposed to a lower temperature than that of the fluid within the thick inner string, the low-density "Super-insulating" Material in each joint of said inner string is, in effect, covered by a thin outer tubular wall presenting at least one thermal expansion device, welded, or brazed, to the thick inner string.

As taught in Ref.(1), for applications in cold environments, two coaxial "Super-insulated" Tubular Assemblies are required in the vertical casing. The Injection Steam (wet, at 80 % quality) flows downward in the smallest-diameter tubular and remains at a nearly constant temperature, determined by the injection pressure, which is slightly higher than reservoir pressure, but safely lower than the reservoir's frac pressure.

The annular space between the outer diameter of the thick protective string of the "Super-insulated" Steam tubular and the inner diameter of the largest-diameter "Super-insulated" tubular string carries the gas-lifted stream of Heated Oil and Steam Condensate from the Production Collector pipe to the Well Head. The temperature of that stream is about 180 F below that of Injected Steam. It is further reduced, on its way-up, primarily by the cooling effect of the expanding, cold, gas-lift gas, by about 40 to 70 F, for a Heavy Oil reservoir such as the Ugnu, on the North Slope of Alaska.

The total heat loss transferred to the casing is then negligible, even for a Total Production of 1,000 BO/D and 2,000 BW/D, both hot, following a Steam injection of up to 3,000 B/D, during 20 days, in each of four Lateral wells, followed by a 10 days-period of "Steam Soak".

TOOLS FOR DOWNHOLE INSTALLATION, MAINTENANCE AND WELL WORK-OVERS

All 3 parts of the Flow Control Apparatus, relative to the selected lateral well, are connected to each other on the Service rig, using existing or modified surface tools, run-in at the end of a work string, and set, by conventional means.

The pre-fabricated Modular elements for all the lateral wells connected to the vertical well are, in fact, individually oriented, stacked upon each other, connected, hung and packed within the vertical well casing. They provide direct access to logging, cleaning or remedial tools, into each lateral well, after removal of a single retrievable plug, by wireline or by coiled tubings.

During a well work-over, the various elements of the well head, "Super-insulated" Steam string, "Super-insulated" Production tubing string and of the Flow Control Apparatus of each lateral well above the selected lateral well have to be dis-assembled and pulled-out prior to the work-over of the selected lateral well. They are, all, disconnected and pulled-out with a Service rig and using conventional or modified SURFACE TOOLS.

BRIEF DESCRIPTION OF THE FIGURES

FIG. A and B are vertical schematic cross sections taken from Ref.(1), US Patent 5,085,275, issued to the present Inventor. Captions for each of the elements have only been added, to make them self-explanatory.

They, both are also labeled "Prior Art", offered for Clarity only.

They both relate to a Process for which the present Invention of various said Apparatus and "Super-insulated" Tubular Assemblies are required, for the same functions, under specific environmental conditions for two or more lateral wells connected to the casing shoe.

FIG.C is taken from Ref.(5), an SPE Publication. It is not part of Invention, but is offered for Clarity only. This Figure is labeled "Prior Art". It is self-explanatory.

FIG.1 is a vertical cross section of the borehole trajectory and typical completion equipment of one of several multi-lateral wells connected to a vertical cased well, through its side window, for its operation under "Sequential Cyclic Steam Injection", in a Cold environment, Onshore or Offshore.

FIG.2 is a vertical cross section of Part 1 of the Downhole Flow Control Apparatus, showing its bottom connections, below the casing window of the lateral well of FIG.1, and its top connections, above

said window, which are in two different radial vertical planes, designated I and II and at two different elevations.

FIG.2A is a perspective top view of the gas-lift tubing guide of Part 1, showing its location with respect to the Production tubing, in the Packer at the top of said Apparatus, for the same lateral well.

FIG.3 is a vertical cross section of Parts 2 and 3 of the Downhole Flow Control Apparatus, within the vertical well casing, below the "Super-insulated" Production tubular assembly. They are both pre-assembled, run-in together, oriented and connected together to Part 1 of the Downhole Flow Control Apparatus, for each lateral well.

FIG.4 is a Schematic flow diagram, for Steam, Lift-gas and Production fluids, within two Flow Control Apparatus, stacked on top of each other, for connection to two of a plurality of lateral wells, at different depths and respectively operated under Production and under Steam Injection.

FIG.5 is a vertical cross-section of the "Super-insulated" tubular assembly for injecting Steam.

FIG.6 is a horizontal cross section showing the two coaxial "Super-insulated" tubular assemblies, carrying respectively Steam in the center and the Production within the annular space between both of the "Super-insulated" tubular assemblies.

FIG.6A is a schematic vertical cross-section of the Multi-lateral well head, showing the connections of both of the "Super-insulated" tubing strings, with respect to the Casing.

FIG.7 is a perspective schematic view of Surface Tools, used for sequentially coupling, first, a new joint of the sealed inner pipe of a "Super-insulated" tubing string and, second, for inserting said inner pre-insulated pipe string into its associated outer protective pipe string, preferably by means of a Service rig, equipped with a conventional "Top drive" system, in addition to the regular rotating table.

DETAILED DESCRIPTION OF THE FIGURES (OTHER THAN "PRIOR ART")

FIG.1 shows the vertical cross section of one of the Multi-lateral wells connected to one of stacked joints of a vertical Casing. For Clarity, it includes elements belonging to Prior Art, in which the cross-hatching was made lighter than that of the present Apparatus, so as to, easily, differentiate them. The same approach also applies to some of the elements of FIG.2.

The "quasi-horizontal" portion of the Lateral hole (1), located within the Heavy Oil zone (2) of the reservoir, is completed with the small-diameter Liner (3), equipped with centralizers (4). This portion of the Liner includes some perforated joints (5), some blank joints (6), some joints equipped with sand screens (7), some landing nipples (8) for wireline-retrievable plugs (not shown), at selected locations within the reservoir. The Liner (3) is terminated at its proximate end (9) by a thermal expansion joint (10), below a hanger/packer (11) set within the lower part of the Curved Liner (12), cemented within the larger curved hole portion of the lateral well. The upper end of the larger Curved Liner (12) is equipped with a hanger/packer (13), set within the cemented Liner Stub (14), held within and sealed to the edge of the Casing Window (15) of one of the cemented joints of the well Casing (16). Within the Tapered Liner String of the lateral well, is the Production tubing string (17), equipped with centralizers (18) with a thermal expansion joint (19), below a hanger (20), set

within the lower part of the Curved Liner (12). The proximate end of the Lateral well liner is equipped with a cup-packer (21), a landing nipple (22), containing a wireline-retrievable plug (23) and a PBR (24). The function of the cup packer (21) is to prevent back-flow of the Steam-lifted Produced Fluids from the annular space between Liner (3)-tubing (17), at the start of each Steam Injection Cycle.

This is the status of one of the Lateral wells, filled with a solids-free completion fluid, before beginning to drill the hole for the next Lateral well, connected to a Casing joint above that of (16).

FIG.2 is a vertical cross section of Part 1) of the Modular Flow Control Apparatus, prior to its full insertion into the Curved Liner of FIG.1. It includes two quasi-parallel curved strings of tubing, (25) and (26), joined together at their lower ends by the upper branches of an H, or Y, welded connector (34), which brings a slip stream of Lift-gas from tubing (26), via gas-lift valve (36), into the produced fluids stream of tubing (25).

Curved tubing (25), the Lateral well's Production tubing, is equipped with a sealing stinger (27), matching the PBR (24), hung within the lower part of the Curved liner of FIG. 1).

The other curved tubing, (26), is the lift-gas tubing. Its lower part is equipped with two modified gas-lift mandrels (28) and (29) suitable for standard 1"OD wireline-retrievable gas-lift valves. The gas-lift mandrel (28) carries a partial stream of dry Lift-gas (30), via its gas-lift valve (31), to Production tubing (25). The other modified gas-lift mandrel (29) carries another dry lift-gas (30), via its gas-lift valve (32), to the annular space within the Curved Liner (12), so as to lift said other produced fluids stream, flowing from the Lateral well Liner annulus upwards to the annulus between Casing (16) and the Collector Production tubing (35). The bottom end of the H connector (34), below tubing (26), is closed with a retrievable plug (36) set within a Landing nipple (37), thus making the H connector (34) equivalent to a Y connector. Temporary retrieval, by wireline, of plug (36) and permanent removal of the plug in Landing nipple (22) allow to fully displace completion fluid from the Lateral well to the surface, by Lift-gas, in order to start Oil production operations from said Lateral well.

The upper end of the Production tubing (25) is equipped with a PBR (38), located within the Liner Stub (14), outside of the window in Casing (16).

The Lift-gas tubing (26) extends within the annular space between casing (16) and the coaxial Collector pipe (35), to be installed with Parts 2 and 3 of said Apparatus.

It is also equipped at its upper end with a PBR (39) supported by a guide (40), set within the casing joint (16). Tubing (26) is connected to a traversing hole (41) in the lower surface of the guide (40), hung within the Casing (16). A plug's landing nipple (42a) and a PBR (43) are successively connected on the upper end of traversing hole (41a), for future isolation of the Production collector pipe (35) from or connection to matching stingers in Part 2) of the Modular Flow Control Apparatus.

FIG.2A shows a perspective top view of the multi-tubular Packer (44), used in Part 2) of the Apparatus for a lateral well and a

comparative top view of the guide (40), used, in Part 1) of said Apparatus, as support of the Lift-gas curved tubing (26) and of its PBR (39). Respectively the PBR (38) and the curved Production tubing (25), in Part 1), are in a different radial vertical plane, than that of Lift-gas tubing (26) and PBR (39), below the plane surface of guide (40). Packer (44) and guide (40), however, are both anchored in casing (16), at a short distance (=< 50 ft) from each other.

The Y, or T, flow connection (49) between tubings (25) and (26a) is controlled from the surface by the "on-off"valve (53), open during the Production cycle of the selected Lateral well, as shown on FIG.2A. Valve (53) is closed, however, during the Steam injection and Steam soak periods of that Lateral well.

Correspondingly, above each multi-tubular Packer (44), there is a plurality of PBR's for distributing Lift-gas from the Casing annulus, through the uppermost Packer, to the lowermost Packer, in all the stacked-up Apparatus, except in the lowest one, which requires only one, stinger-equipped, Lift-gas tubing (26a), hung from a lateral branch of tubing (25a), below Packer (44) and above a retrievable plug (51). Said plug, when removed, provides full access to the specific Lateral well's production tubing (25), via a stack of parallel extension tubings (26a), normally used for conveying Lift-gas from the Casing annular space, all the way down to each of the other Lateral wells.

FIG.3 shows a vertical cross section of the Modular Assembly of Parts 2) and 3) of the Flow Control Apparatus, combined for a specific Lateral well.

Part 2) is a welded Assembly of a plurality of quasi-vertical pipes, each one with a sealing stinger (43) at its lower end, matching a PBR (39) of the upper ends of Part 1) of the Flow Control Apparatus, and any of those above each Packer (44) shown on FIG.2. These pipes are arranged around a central joint of the shared Collector pipe (35), which belongs to Part 3), pre-installed on the axis of the vertical Casing (16).

These pipes, dedicated to the specific Lateral well, include, from the bottom-up:

- a sealing stinger (38a) of the lower end of an extension of Production tubing (25a), matching PBR (38), at the top of Part 1) of said Apparatus,
- an extension of the Lateral well Production tubing (25a), covering the interval between said stinger (43a) and a traversing hole through the multi-tubular Packer (44), leading to PBR (52), at the top of the Modular Assembly and, from there, to a stack of Lift-gas feeder supply pipes, through all the Modular Assemblies stacked above Packer (44), and carrying Lift-gas from the casing annular space, all the way down to PBR (39), at the top of Part 1) of the Modular assembly, in FIG.2,
- in said extension (25a) of the Production tubing, the retrievable 3-way Valve (45), primarily used to switch the Lateral well from Steam injection to Oil Production, and
- three lateral Y, or T, branch tubular connectors, all originating from tubing (25a), and located below the retrievable plug (51).

Said branch connectors include, from the top down:

a) the slanted branch of the inverted Y connector (49) leading, via an "on-off" valve (53), below Packer (44), to the upper end of a

Lift-gas extension pipe (26a), within Part 3 of the Modular Assembly, and, above said Packer (44), via said stack of Lift-gas feeder supply pipes (58) in all the super-imposed Modular Assemblies, ultimately leading, via the gas-filled Casing Annulus, to the well head Lift-gas supply line, at the surface,

b) the Upper lateral Y, or T, branch (46), leading to the axial Collector pipe (35), when the 3-way Valve (45) is closed to the shared Steam tubing (48), and open to Production fluids,

c) between said Upper lateral branch (46) and said 3-way Valve (55), a first Float valve (32a), set in a standard gas-lift mandrel (29a) to allow the entry of a Production fluids slip stream into tubing (25a), from the casing annular space below packer (44), only when the level of the liquid phases (Oil and water) of said Production fluids is high in said annular space (i.e. during the Lateral well's Production cycle}, but not when said liquids level is low (i.e. during the Steam injection and Steam soak periods),

d) the Lower lateral Y, or T, branch (47), which leads, via the side inlet of the 3-way valve (45), to the Insulated Steam tubing joint (48), coaxially located within the bare Production Collector pipe (35).

Conversely, a Lift-gas feeder extension pipe (26a), leading from said slanted branch (49) of the Y connector, above said "on-off" valve (53), via an extension of Lift-gas tubing (26a) to another gas-lift mandrel (28) and, via a second Float valve (31), to the Bottom Lateral branch (57) of a Y, or T, connector, delivers Lift-gas from (26a) to carry a slip stream of Production liquids from the Casing annular space to the Production Collector pipe (35). This transfer of Production liquids from the casing annular space into pipe (35) only takes place during the Steam soak period. It automatically stops when the liquid level in the casing annular space has dropped below the 3-way valve (45), when Steam rising into the reservoir has sufficiently reduced the casing pressure, before the start of a new Production cycle.

Table 1 summarizes the position of each type of plug or valve in each of the three parts of the Flow Control Apparatus, for each of the three modes of operation of the Lateral well, as an example of the Flow Control Apparatus.

Of all the Part 3) tubulars dedicated to the specific Lateral well, only PBR (52) is above Packer (44); the other tubulars above (44) are either shared by all wells, such as (35) and the Insulated Steam tubing, or they belong to the Lift-gas distribution systems of other Lateral wells.

This disposition limits the number of peripheral traversing holes through the Packer (44) to one, for the lowermost Packer, and to a maximum of eight, through the uppermost Packer of the eighth Lateral well,

The conventional "on-off" Valve (53), hydraulically-operated from the surface, and retrievable by wireline, is set in a mandrel (53a), above the stinger of the Lift-gas feeder extension, located just below the retrievable plug (51). When Valve (53) is open, the partial Lift-gas stream, distributed to the selected Lateral well, flows down

from a gas-filled Casing annulus to the Lift-gas extension pipe (26a) and from there to the curved tubing (26) and back-up to the surface, via the gas-lift Valve (31) in its mandrel (28) to the Production tubing (25) and its extension (25a), into the Production Collector pipe (35) and, from there, via the "Super-insulated" Production tubular, to the surface.

Conversely, the Production stream from the annulus between the "quasi-horizontal" Liner (3) and tubing (17) is lifted-up by Lift-gas delivered by the curved tubing (26) to the annular space between the Curved liner (12) and the twin tubings (25) and (26), via the gas-lift Valve (32) in Mandrel (29).

The resulting lightened stream is then delivered, first to the annular space of Casing joint (16) and, from there to the Production Collector pipe (35) via an open Float Valve or Standing Valve (31a), preferably retrievable from a modified gas-lift mandrel forming a welded H joint with Collector pipe (35).

This arrangement of parallel pipes in the Casing annulus, below the "Super-insulated" Production tubular, reduced their number from one, in the lowermost Modular Assembly, to a maximum of 8 for the uppermost Modular Asssembly, for a maximum stack of 8 lateral wells.

Each lateral well tubing string (17) is accessible via its own Production tubing (25), after removal of the single retrievable plug (51) by wireline tools, from the surface, through the stacked Lift-gas feeder extension tubings (26a) and the gas-filled Casing annular space.

The connection, by means of a sealing stinger in a PBR, of each of the stacked Lift gas extension pipes (26a) provides flexibility when the length of the much hotter Production Collector pipe (35) increases, from the fluids heat.

The same type of flexible sealed connection is used for each Production Tubing (25), in addition to the Thermal expansion joint (19) at the upper end of the "quasi-horizontal" tubing string (17).

The entire tubing completion, described above and in FIG. 1 to 3, is run-in, oriented and installed by conventional means, using a standard Service rig.

Each Lateral well may be temporarily isolated by two wireline retrievable plugs, respectively closing its Production tubing and its Lift-gas tubing. The completion fluid in the casing above the uppermost Apparatus is displaced out and replaced by dry air or gas, at atmospheric pressure. The vertical well is then ready to receive, first, the protective tubing string of the Production tubular, second, the Production coaxial "Super-insulated" tubular, third, the protective tubing string of the Steam coaxial "Super-insulated" tubular and, finally, the Steam coaxial "Super-insulated tubular.

During the life of any Lateral well, for any repairs, the tubing completion may be dis-assembled by conventional means, using a Service rig. The procedure is the reverse of that used for its installation.

FIG.4 is a Schematic Block Diagram showing, with arrows, the flow paths of the various Fluid Streams of 2 Lateral wells, simultaneously operated respectively under Steam injection, on the Right side, and under Production on the Left side. A legend shows the symbols used respectively for: - the Production Flow Stream, from both the Lateral

well's annular space and from its Production tubing.

- the Steam Flow Stream, within the Lateral well
- the Lift-gas Flow Stream, before and after it is mixed with the Production Stream.

This Block Diagram illustrates and summarizes the previous description of Part 1), Part 2), and Part 3) of the Downhole Flow Control Modules of two of the Lateral wells, in relation with the shared facilities: the gas-filled upper Casing annular space, the "Super-insulated" Production tubular assembly, and the "Super-insulated" Steam tubular assembly.

FIG.5 is a vertical and radial cross section, showing the upper coupling end of the "Super-insulated" Steam tubular. It includes the Box (54) of a lower joint of the inner tubing (55), designed for always carrying Steam, under the selected mode of Operation of the Multi-lateral Well.

The Box (54) is located on the same vertical axis as a matching pin (56) of the next Steam tubular joint (55a) above tubing (55).

The threads (59), in Box (54), are of one of the conventional types which provide a metal to metal seal, against the male threads of the pin (56a) to which they will be tightly coupled, after a specified torque has been applied to their coupling.

Below the Box (54), a thin corrugated metal collar (60) has been affixed and sealed, by welding or brazing, to the outer surface of the Steam tubular (55), along the entire circumference of tubing (55). At a short distance below Collar (60), a Centralizer metal guide (61), also affixed to the outer surface of (55), presents a plurality of radial extensions (62), sliding within matching longitudinal guides (63), affixed to the inner surface (64), of the outer tubing (65).

Both tubings (55) and (65) are coaxial and the guides (63) are parallel to the common axis of tubings (55) and (65).

It will be apparent to the Man of the Art that this combination of the metal centralizer extensions (62) and guides (63), in which they slide, prevents the outer tubing (65) from rotating around its coaxial inner tubing (55). The only relative motion allowed by such devices, between the two tubings (65) and (55) is that of a translation along their common axis. The number of such devices per joint is also not limited to two. All other means for achieving the same goals, are also included in the present Invention.

The metals of collar (60) and centralizer guide (61) are chosen for their relatively low thermal conductivity, low thermal expansion and high strength, such as those of alloys containing two or more metals taken from the alphabetic list of: Aluminum, Antimony, Cadmium, Copper, Chrome, Iron, Manganese, Molybdenum, Nickel, Silicon, Silver, Titanium, Vanadium and Zinc.

The metals of the insulation cover tubing (65) are chosen primarily for their ease of assembly, by welding or brazing, with the alloys of collars (60) and for their thermal expansion, higher than that of steel, such as Zinc or Aluminum alloys, in order to minimize the difference between their thermal expansion with that of the inner steel tubular (55), which operates at a much higher temperature than the insulation cover tubing (65).

The annular space between (65) and (55) is factory-filled with

fibrous "Super-insulation" (66). The outer edge of extended Collar (60) is also affixed and sealed, preferably by welding or brazing, to the inner surface of the outer thin tubing (65).

In a First Embodiment of the Invention, the twin tubings (55-65) and (55a-65a) of two superposed joints of factory-assembled "Super-insulated" Steam or Production tubulars, (the index "a" meaning "above") respectively present similar coaxial systems including, but not limited to:
- a Centralizer metal guide (61a), with radial wire-type extensions (62a) sliding into matching guides (63a),
- two circularly corrugated metal collars (60),(60a), closing the top and the bottom of the annular space between the coaxial tubings (55-65) and (55a-65a) and supporting the fibrous "Super-insulation" (66a).
- a granular "Super-insulation" ring (69), pre-packed in metal foil at the factory, and fitted, on the rig, over the collar (60), so as to fill the annulus between the ends of tubing joints (55) and (65), prior to making-up, by conventional means, the coupling operation of the upper and lower joints of either Steam or Production tubulars strings:
- The lower joint (55), or (65), is held in Slips, and the upper joint (55a), or (65a), is held in the rig's Top-drive. They are then coupled together, in the rig, by a standard, pin to box, threaded, welded or brazed connection.
- The joints are inserted into their respective thick, protective, air-filled, tubular string (70), for Steam, or (71), for Production fluids, previously run-in and assembled, at their lower ends, into their corresponding PBR or threaded coupling, located at the top end of the uppermost Flow Control Apparatus. All six coaxial tubular strings, (73), (72), (71), (70), (65), (55), at their upper ends, are sequentially hung in the well head and held in tension, by means of conventional devices.

FIG.6 is a horizontal cross section of the two coaxial "Super-insulated" tubulars,(65/55) used for carrying, respectively, Injection Steam, at the center, and the surrounding Production tubular (70/72), also "Super-insulated". The Production stream flows in counter-current to that of Steam. The insulation thickness of of the Steam tubular is based upon the Steam temperature (nearly constant), which is related to reservoir depth. The temperature of the Production tubular, which is much lower and declines, from the bottom-up, allowes the use of a different fibrous, lower-cost, "Super-insulation" material.

FIG.6A is a schematic vertical cross section of the Vertical well head and casing, showing the surface connections (some of them them hot) of both of the "Super-insulated" well tubulars, in relation the cold Casing (16).

The length of the "Super-insulated" Steam tubular (55) extends almost to the base of the vertical Casing, but that of the "Super-insulation" in the Production tubular string (71) stops a short distance above the uppermost multi-tubular Packer (44).

The inner (71) and outer (72) tubings of the "Super-insulated" Production tubular string, and their Protective tubing string (73) are

all respectively hung to the Well head and remain under tension, so as to prevent buckling.

On FIG 6A, the bottom end of (73), which remains relatively cold, is directly coupled to the hot bottom end of (71) by a modified thermal expansion joint (74), which provides a pressure-resistant annular barrier to protect the "Super-insulation" compartment (71/72) from any fluid entry from either the pressurized gas-filled Casing annulus or from any accidental leak of Production fluids into said Casing annulus, from the Stinger-PBR connection of tubing (71) with the uppermost joint of the Production Collector pipe (35). Similarly, the Protective tubing string (70) of the "Super-insulated" Steam tubular string (55/65) is hung in the well head and connected, at its bottom end, to the Apparatus' tubing (55), via a modified thermal expansion joint (75), so as to protect the "Super-insulation" in the annular compartment (55-65) from any entry of Production fluids or of any high pressure Steam, possibly leaking from the Stinger-PBR connection of the inner tubular string (55) with the Production Collector pipe (35), at the top of the uppermost Packer (44). The modification of the thermal expansion joints (74) and (75) and of the seals in the Stinger/PBR connections includes the addition of one or more Graphite ring seal (76), under compression.

In a Second Embodiment of this Invention, it is the outer Protective tubing string (70) which supports "Super-insulation" (66). Corrugated collars (60, 60a) and the insulation cover tubing (65) are now affixed, by welding or brazing, to the outer tubing (70), thereby providing a sealed enclosure to the fibrous "Super-insulation". The inner diameter of the insulation cover tubing (65) is only slightly larger than the Steam tubing outside diameter. It is also coated with a graphite suspension lubricant. The inner Steam tubing threaded string (55), in this case, may advantageously be replaced by a coiled tubing string, inserted within the insulation cover tubing (65), and sealed within the Apparatus' PBR matching the Protective tubing (70), as the last step of the vertical cased well tubing completion. This substitution totally eliminates the risk of damage or contamination of the "Super-insulation" by any high-pressure Steam leak, since there are now no joints in the Steam tubing string (55). In addition, a film of dry, low pressure Lift-gas circulates in the very thin annular space between the coiled tubing (55) and the insulation cover tubing (65), as a further shield from the entry of moisture into the sealed insulation space via the welded or brazed joints of tubing (65).

The metals of choice for that small-diameter coiled string is then Titanium and its alloys, which are also corrosion resistant and subject to a lower thermal expansion than steel. The higher cost of Titanium is partially offset by a reduction in the cost of tubing (65), which has a smaller diameter than in the First Embodiment.

The thin-gauge metal of the insulation cover tubing (65), now being at a higher temperature than its support, namely the protective tubing (70), is now selected for its lower thermal expansion coefficient than that of the steel of tubing (70), in order to reduce their differential expansion. Such low thermal expansion alloys are found among high Nickel alloy steels, such as "Invar", as well as among, more costly, Titanium alloys.

The designs of the "Super-insulated" Production tubulars (71), (72) and (73), associated with the new (55), (65) (70) could, perhaps, remain as in the First Embodiment, thereby combining both embodiments in the same vertical well, as shown on FIG. 6A. A circulation of a slip stream of dry Lift-gas within the thin annular between (71) and (72) remains very advantageous, however, when (71) is a threaded pipe string, more prone to water vapor leaks than the coiled tubing string of (55).

FIG.7 is a perspective drawing and radial cross section of some tools to be used at the factory and on the rig, for centering each joint of Steam tubing (55) and its insulation cover tube (65), in the First Embodiment.

Both ends are equipped with corrugated collars (60), at the factory, where they are inserted and slide freely within their thick protective tubing (70). To facilitate such insertion, graphite-based lubricants coat the inside surface of of tubing (70).

A box-type thread-protector (77), presenting a central plug, is inserted within the lower end of tubing joint (55) and screwed around the pin of the tubing joint (70). Conversely, a pin-type thread-protector (78) is simultaneously inserted into the boxes at the upper end of tubing joints (55) and (70), thereby insuring that the temporary assembly of the "Super-insulated" joint (55), within its Protector tubing joint (70) can be laid down, shipped to the well-site and handled by the rig as a single element, without any damage to the "Super-insulation" nor to its thin-gauged, sealed, protecting cover tube (65). With this element vertical and tubing (70) firmly held in slips, the upper pin-type thread-protector (78) is then removed, the box-type upper end of tubings (55) and its insulation, sealed within its cover tube (65) is grabbed by the Top drive's pipe handler and handled as a whole to the vertical rack, for temporary storage. After removal of (77), the remaining protector tubing joint (70) held in the slips is then added to the string of previous joints (70) and run-in and set in the previously installed "Super-insulated" Production tubing (73/72/71), using the same means.

Thread-protectors (77) and (78) are surface tools provided by the factory licensed to supply all the "Super-insulated" tubings.

Most Top Drive rigs already include a Torque Wrench, equipped with a Torque Indicator, which insures that torque applied to each of the coaxial threaded couplings of pipe joints (73), (71), (65) and (55) have specified decreasing values.

Additional surface tools, used on the rig, also include welding or brazing machines for sealing the "Super-insulation" of threaded couplings, respectively used in both embodiments of the Invention.

In the First Embodiment, the circular edges of the Steam tubular joints (55) and (55a), respectively held stationary in a coaxial position by the slips of the rotating table and by the Top Drive, are used for guiding the roller electrodes (79), (79a) of a conventional rotating "seam welding" machine, around the circular edges of the sheet metal of the insulation cover tubings (65) and (65a), which are pressed together by said rollers (79) and (79a), prior to the insertion of the coupling of the insulated tubing joint of (55) within its pre-installed Protective tubing string (70).

In the Second Embodiment, a similar type of welding, or brazing

machine is inserted within each joint of the tubular string (65), and guided around to seal the circular edges of the "slick" box and pin sheet metal coupling of the "Super-insulation" cover tubing joints (65) and (65a), after the associated coaxial Protective joints (70) and (70a) have been coupled together and torqued, prior to being run-in.

In view of the importance of keeping the "Super-insulation" very dry, the leak-proof quality of each "seam weld" is monitored first during the welding operation of each joint of said insulation cover tube. This is done by checking the absence of moisture in a very dry, light gas, such as Helium, injected, at low pressure, by a wireline-retrievable small gas tank within the temporarily plugged end of each of the two sealed insulation cover tubular assemblies, while the string is being run-in. The same instrument is later used as a surface tool, throughout the lifetime of the multi-lateral well, using a slip-stream of dry lift-gas (mostly Methane) under permanent circulation, from the casing annulus, back to the surface, to detect any moisture content, picked-up either from defects in said "seam welds", or due to any leaks of Steam or of Steam Condensate, or of formation water in the system, while in operation.

While certain embodiments and materials of the invention have been specifically disclosed, it should be understood that the invention is not limited thereto, as many variations will be apparent to those skilled in the Art and the invention is to be given the broadest possible interpretation.